CONCEPT DISCUSSION PAPER FOR
AN ELECTRIC INDUSTRY TRANSMISSION AND MARKET RULE

by the Staff of the Federal Energy Regulatory Commission

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This paper represents the views of the FERC Staff. It is intended to facilitate discussion on RTO policy regarding a standard market design. It discusses questions in two areas:

1. What is our vision for the future of the electric industry, say, 5 or 10 years from now?

2. What functions must be performed to make this vision a reality?

In discussing these issues, the paper also addresses issues raised by the Electronic Scheduling Collaborative (ESC) regarding market standardization.

1. WHAT IS OUR VISION FOR THE FUTURE OF THE ELECTRIC INDUSTRY, SAY, 5 OR 10 YEARS FROM NOW?

By 2006-2011, electricity will be purchased and sold in both wholesale and eligible retail markets by any willing creditworthy participant. Markets will clear with competitive prices. Competitive prices will function so as to ration existing supplies efficiently in the short run and to elicit adequate technology and infrastructure in the long run, so that there will be no involuntary curtailment of service at market prices. Electricity markets will be both transparent and liquid, and market participants will have opportunities to hedge risks. Although regulation of monopoly service providers will continue, even these monopolies will feel some pressure of competitive market forces.

Wholesale electricity markets will have the following characteristics:

- Wholesale energy-related products, such as transmission and power, will be fully unbundled to the extent that there is no monopoly advantage left due to vertical integration. In other words, anyone will be able to purchase the products and services necessary to buy or sell "delivered" electric energy for themselves, or as a service provider for others.

- There will be relatively few barriers to entry and exit, and those that do exist will be as low as is reasonably possible to obtain. There will be no significant barriers to innovation.

- Market participants will not be able to exercise market power in generation or transmission markets. Ownership or control of physical assets will not convey (will not be allowed to convey) significant market power.

- Market institutions will exist that maintain market transparency and keep transactions costs low, while affording liquidity for both the short-term and long-term markets.

- Good market-driven price signals will exist to support well-planned investment in new generation and new transmission when and where they are needed, and in a timely manner (before shortages occur).

- Buyers will receive accurate and timely price signals and will have the ability to react to them, so that they can make rational and efficient choices in the amount of energy they consume at any given point in time. As a result, demand will be responsive to market price changes.

- Non-investor owned entities (e.g., public power and electric power cooperatives that are financed by the Rural Utilities service) will be allowed (even encouraged) to join regional organizations (including RTOs), and will be treated comparably with investor-owned entities. They will not face disincentives to join RTOs, but neither will they be given special treatment.

- Where states don't provide for retail choice, there will be competition in wholesale markets to allow local utilities to acquire electricity at reasonable prices.

- Where states have approved retail choice (and thus, where retail products are fully unbundled to the extent that there is no monopoly advantage left due to vertical integration), the wholesale market structure will not prevent anyone from purchasing the products and services necessary to buy or sell "delivered" electricity for themselves, or as a service provider for others.

Transition issues

There will need to be a transition in achieving the vision. For example, we recognize that there are existing contracts. Dialogue will be necessary to evaluate the options for getting from the status quo to the desired end state.

2. WHAT ELECTRIC INDUSTRY FUNCTIONS MUST BE PERFORMED TO MAKE THIS VISION A REALITY?

This vision cannot be met currently, because many electric industry functions are currently performed separately by individual electric utilities in nonstandardized ways. In order to remove barriers to regional trade, greater regional coordination and standardization is needed in performing key industry functions. This paper identifies major industry functions that must be performed and describes in general terms what Staff would propose to include in a Rulemaking to standardize the functions. There are several different entities that could perform these functions. While we conclude that these functions must be performed to achieve the vision, we don't decide here which entity should perform them.

An independent regional provider must:

1. **Offer nondiscriminatory rates, terms and conditions of transmission service under the OATT to all transmission customers.** (Interconnection NOPR would do the same for interconnection service.)
   - No preference should be given for particular types of load, e.g., retail versus wholesale
   - No preference should be given for transmission owners that are also control area operators, e.g., imbalances
   - No preference should be given for transmission reserved by customers for native load versus other loads, e.g., no special rates or conditions for capacity benefit margin (CBM) or for future load growth
   - Existing transmission contracts should be converted to standard RTO transmission rights. How should this be implemented, and over what time frame? How should fairness to existing contract holders be taken into account?

2. **Perform certain basic Order No. 2000 RTO transmission on a regional basis.** We view the regional grid, including both privately owned and publicly owned facilities, as a single facility and conclude that certain practices cannot be

performed justly or reasonably on an individual company basis. For example, the following practices and functions must be performed regionally:

i. Coordinating transmission maintenance schedules
ii. Ensuring short-term reliability
iii. Offering a nonpancaked regional transmission tariff that eliminates intraregional contract path pricing, which requires that:
    a. Total Transmission Capability (TTC) and Available Transmission Capacity (ATC) be calculated regionally. *ATC calculations should not be made on a contract path basis while ignoring parallel path flows*
    b. Parallel path flow be coordinated with other regions in the interconnection
    c. A regional OASIS be provided.
iv. Procuring ancillary services
v. Planning and expanding the transmission system on a regional basis. *A 5-year transmission plan should be developed annually for each region. The plan should: identify areas of congestion; determine whether the congestion is likely to be temporary or long-term; and identify options for relieving long-term congestion, including identifying locations for development of new transmission, generation, or demand-side management facilities. The options should allow for both merchant transmission as well as system expansions.*
    a. Participating in a regional expansion cost allocation plan. *The benefits of an expansion may be distributed widely, and the costs of system expansions must be borne by all parties who benefit from the expansion. Otherwise, incentives to expand may be blunted, because one party must bear all the cost while getting little or none of the benefits. The Commission should prescribe by rule whether expansion pricing will be based on a rolled-in or incremental cost basis (or a combination), but in either case, regional costs that benefit multiple regional parties must be shared regionally. The Commission should tie together transmission pricing for expansions and interconnect pricing, to ensure consistency.*
    b. Determining the transmission rights that result from (and should be issued to the entity financing) a capacity expansion
vi. Coordinating with other regions on reliability, loop flow, ATC calculation, and planning and expansion. Should the Commission standardize the rules and pricing for transfers between RTOs?

However, an individual company may continue to take emergency actions to relieve instantaneous transmission overloads (when there is not enough time for a market-oriented congestion management system to be used).

3. Operate certain markets.

Certain markets need to be operated – and operated efficiently – to achieve the vision. Among other reasons, these markets are necessary so that the RTO can operate the transmission system efficiently and reliably in real time. The Commission has learned considerably from its experience with markets for energy and transmission service operated by independent system operators and from studies and analyses by industry experts. The Commission has seen which market designs for these markets have succeeded and which designs have failed. Based on this learning, Staff is ready to make recommendations to the Commission regarding the design of certain energy and transmission markets (in Items i - iv, below). In other markets – for operating reserves and longer term capacity obligations (Items v - vi, below) – our experience has not always provided us with firm conclusions. In these areas, we offer both recommendations and questions that need further exploration.

The recommendations below are based on several general principles. Participation in RTO markets should be voluntary. [1] That is, the market participant should have the option to sign a bilateral contract for, or self-supply, the product or service (including losses). The ability to self-schedule may be particularly important for certain categories of generators, such as hydro resources (in light of recreational and environmental considerations) and nuclear and other large baseload resources (in light of their large start up costs). Moreover, RTO market designs should support customer choices for acquiring particular products or services, and they should allow demand-side options to compete equally with supply-side options as much as is technically feasible. The RTO market design should not interfere with the decision to transact outside RTO markets; where possible, RTO market designs should promote the ability of market participants to transact outside RTO markets or accommodate developments in those markets (for example, by designating nodes as trading hubs). However, transactions outside RTO markets should not be promoted artificially through market design features that inhibit the efficiency or completeness of RTO markets.

In each region, an entity independent of market participants should:

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[1] Unless a market participant voluntarily commits by contract to bid into the RTO markets (e.g., as in the case of Installed Capacity (ICAP) contracts), or unless a bidding obligation is adopted as part of a market power mitigation plan.

i Operate a real-time energy market – bid-based, with locational market-clearing prices. A real-time energy market is necessary to allow an RTO to balance generation and load and to manage congestion reliably and efficiently.

a. Locational energy prices at different nodes should reflect transmission congestion and losses. Nodes may be aggregated into zones, so long as no congestion costs are socialized.

b. The market operator should be allowed to dispatch sellers and buyers based on their voluntarily submitted real-time bids whenever it is efficient to do so, even if not necessary for reliability.

- C For example, the market operator could be allowed to direct a supplier with a low bid to produce additional energy while simultaneously directing another supplier with a higher bid to reduce energy production.

c. Should a penalty be imposed on market participants for transacting without the grid operator's approval in the real-time market? Or should all participants face the same locational market energy price, whether or not they transact with the grid operator's approval? If penalties are imposed, should intermittent generators be exempt from them?

- C *Option 1: Impose a penalty for uninstructed generation or load* - All sellers (and buyers) who produce (or consume) at the instruction of the grid operator should face the applicable locational energy price. Other sellers and buyers who produce or consume unscheduled energy without instruction from the grid operator should face a "penalty" that departs from the applicable locational energy price, in order to encourage participants to submit bids to the grid operator and to follow the operator's instructions. This option is based on the view that grid reliability can be jeopardized if market participants' transactions depart significantly from the forward schedules approved by the grid operator. Thus, unscheduled generation and load that shows up in real-time without instruction from the grid operator should be discouraged through a significant penalty. Such penalties would discourage attempts to manipulate the real-time market through gaming.
- C *Option 2: Don't impose a penalty* - All participants at a given location and time should face the same energy price; there should be no “penalty” for transacting in real-time, which could discourage efficient trades that become known at the last minute. This option is based on the view that grid operators can reliably accommodate real-time departures from schedules within a broad range. Moreover, real-time generation and load commonly departs from forward

schedules due to uncontrollable factors. For example, intermittent generators (such as wind and run-of-river hydro generators) may be unable to precisely predict their ability to generate; generators experience unexpected forced outages; and weather patterns can change unexpectedly so as to alter the demand for electricity.

- *Option 3: Charge for the costs of transacting in real time; impose penalties only when the grid operator sees a reliability threat* - This option is based on the view that uninstructed generator and load may create costs that aren't created by transactions scheduled in advance and when participants follow the grid operator's instructions, even though such transactions don't ordinarily create reliability risks. For example, operating reserves are procured to allow the grid operator to balance the system when supply or demand departs from their schedules. Thus, it may be reasonable to impose a pro rata share of the cost of operating reserves on participants that deviate in real time from their schedules without instruction from the grid operator. In addition, under this option, the grid operator would impose additional penalties to discourage uninstructed real-time transactions only when it concluded that they were threatening reliability.

ii. ***Operate a day-ahead energy market*** – it should be *voluntary* and bid-based, with locational market-clearing prices. Both sellers and buyers would be able to participate in the market. It would be used in developing the RTO's day-ahead schedule. A day-ahead market would make it easier for market participants to develop day-ahead schedules that they can honor during real-time operations. Hence, day-ahead schedules would be a more accurate forecast of real-time operations, so the grid operator can more easily operate the grid reliably. It also would facilitate demand-side price response, because it would give buyers time to respond to prices. Buyers could see, and lock in, prices a day in advance of delivery and make adjustments in activities that use electricity (such as adding or canceling a manufacturing production shift) that might not be possible in response to prices announced in real time.

a. Thus, market participants should not be required to submit balanced schedules (where supply and demand are equal).
b. Accepted offers to sell or buy should be financially binding at the applicable day-ahead market-clearing price.
c. Market participants should be allowed to schedule bilateral transactions and/or self-supply as an alternative to participating in the RTO's day-ahead energy market.

d. Locational energy prices at different nodes should reflect transmission congestion and losses.

e. Sellers should have the option of submitting multi-part (3-part?) energy bids to reflect energy price bids, as well as start-up cost-bids and minimum-load bids, and various operational constraints, such as minimum run times , ramping constraints, etc. (Should sellers be required to submit the same price bid for all hours of a day?) Buyers should also have the option of submitting multi-part energy bids to reflect, for example, the maximum bill they are willing to pay over the day or their minimum purchase time.

iii. ***Operate a day-ahead transmission service market*** – it should be a bid-based market, operated jointly (and optimized simultaneously) with the day-ahead energy market, in order to develop a day-ahead schedule for transmission service. A day-ahead transmission service market would allow the RTO to manage congestion more efficiently and reliably. The day-ahead transmission service market would permit entities desiring to complete bilateral energy transactions to acquire the necessary transmission service to complete the transactions. Where demand for transmission service exceeds the available transmission capacity, the bid-based market would allocate transmission service to those who value it the most.

a. The transmission prices (i.e., congestion prices) developed in this market should be consistent with the locational energy prices developed in the energy market. That is, congestion prices for transmission between two locations should equal the *difference* in energy prices at those two locations.

b. No congestion costs should be socialized.

c. Transmission service should be use-or-lose, to prevent withholding. That is, transmission capacity sold in the day-ahead market that is not used by the day-ahead purchaser in real time should be made available for the real-time energy market. The day-ahead transmission purchaser would be paid the applicable real-time congestion price for transmission service that is not used in real time.

d. All physical transmission service should be procured through the day-ahead transmission market. (A physical transmission right is defined here as the right to physically inject energy at a location and simultaneously physically withdraw energy at another location.) No longer-term physical rights should be procured. However, long-term financial rights (which can allow customers to lock in a fixed transmission price over the long term) should be available, as discussed in (iv) below.

   * Should physical rights between RTOs be offered?

iv ***Issue financial transmission rights*** – that allow the holder to hedge uncertain transmission congestion prices.

a. Financial transmission rights are defined here as the right to collect the applicable congestion revenues associated with the applicable transmission path or flowgate.
b. The RTO should offer both point-to-point financial rights (such as TCCs or FTRs offered in New York and PJM) and flowgate financial rights.
c. Holding financial transmission rights should not be a prerequisite to scheduling and receiving physical transmission service; anyone willing to pay the applicable transmission congestion charge should receive physical transmission service.

v. ***Operate an operating reserves market*** – Market participants should be allowed to self-supply their share of operating reserves (as long as they procure any associated transmission service that is needed). However, to the extent that participants do not self-supply reserves, the RTO must procure them. An operating reserves market is necessary to allow the RTO to procure operating reserves, since the RTO does not own generation capacity. The market should allow both generators and demand-side participants to offer reserve products that meet the requisite technical requirements. What type of market should the RTO operate to procure operating reserves? Should it be a day-ahead bid-based market? (If so, it should be operated jointly [and optimized simultaneously] with the day-ahead energy and transmission service markets.) Should the RTO also operate a real-time market for operating reserves? Should the RTO procure operating reserves in a longer-term, contracts market, or should long-term contracting be the responsibility of LSEs? Should the RTO adjust the amount of reserves that it procures based on the cost of procuring them? Should separate reserve requirements be established at different locations, in light of transmission constraints?

a. Operating reserves include at least regulation (AGC) and 10-minute spinning reserves. The Commission should also consider including various non-spinning reserves as well.
b. If a bid-based market is operated, participants should be allowed to submit capacity availability bids as well as energy bids. Participants selected to provide reserves would be paid the applicable market-clearing price, which would reflect both capacity availability bids and the opportunity costs of not selling energy.
c. How should the costs incurred by the RTO to procure operating reserves be recovered from market participants?

vi. ***Administer a regional long-term generation capacity obligation?*** Is it necessary or desirable to impose such an obligation? Proponents argue that an obligation is necessary to ensure that sufficient generation investment is made to avoid shortages and involuntary curtailments. Opponents argue that the obligation is not necessary if demand is sufficiently price sensitive and if regulators don't prevent prices from spiking. If these latter conditions are met, prices would ration limited supplies in the short term and elicit adequate investment in the long term.

4. Develop and administer a program for monitoring the RTO market.

Each RTO needs to establish monitors to ensure the performance of the electric power, ancillary services, and electric transmission markets in its region (see above). In order to achieve this, it would need to establish a process for developing periodic reports on prices, volumes, supply, demand, liquidity, and ownership structure and concentration of these markets. These reports should be sent concurrently to FERC and the RTO without the RTO's prior review. The monitor would also work with FERC and other monitors to develop market performance measures that are common to all U.S. regions. The combination of reporting on the performance measures and factual reporting would allow the monitoring unit to answer questions such as whether or not barriers to entry exist or if demand is being satisfied in the most efficient manner. In addition, the market monitor would recommend structural or rule changes that would benefit market performance. Such recommendations would appear in the monitor's periodic reports, or in special reports devoted to a particular issue. The proposed rule should solicit comment regarding what information should be posted publicly by the monitor to promote market transparency, as well as to allow the Commission to fulfill its own monitoring and oversight responsibilities. The market monitor, while working inside the RTO and funded by the RTO, should have an independent reporting relationship to FERC and maintain a more informal reporting relationship with the management of the RTO (i.e., 'dotted' line).

5. Develop a market power mitigation plan for use in appropriate circumstances.

Under certain circumstances, the market monitor may see a need for market power mitigation measures. The monitor should develop recommendations for market power mitigation measures and submit these recommendations to FERC for consideration. Where possible, the mitigation measures should be applied en ante, rather than ex post. The mitigation measures may not need to be as stringent once demand response has improved. A goal should be to attempt to develop mitigation measures that do not inhibit demand responses to price as well as other innovations that, by themselves, will do much to mitigate market power.

In the Standard Market Design Rulemaking, the Commission should also consider whether to develop a standard market power mitigation plan for all RTOs. If such a plan were developed, each RTO and/or its market monitor would be put in the role of implementing a Commission-approved mitigation plan, rather than mitigating market power on its own initiative. Any standard mitigation plan would need to consider at least two issues:

a. What alternative mitigation measures should be considered?
b. What events or conditions should trigger the mitigation measures?